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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

TOM FORESE – Chairman
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BOYD DUNN

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	Docket No. E-01345A-16-0036
IN THE MATTER OF FUEL AND PURCHASED POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY.	Docket No. E-01345A-16-0123 **NOTICE OF FILING DIRECT TESTIMONY (RATE DESIGN) AND EXHIBITS OF KEVIN C. HIGGINS ON BEHALF OF FREEPORT MINERALS CORPORATION, ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION AND CALPINE ENERGY SOLUTIONS, LLC, CONSTELLATION NEW ENERGY, INC. AND DIRECT ENERGY, INC.**

Freeport Minerals Corporation, Arizonans for Electric Choice and Competition (collectively "AECC") and Calpine Energy Solutions, LLC ("Calpine Energy"), Constellation New Energy, Inc. ("CNE") and Direct Energy, Inc, ("Direct Energy") hereby submit the Direct Testimony (Rate Design) and Exhibits of Kevin C. Higgins on behalf of AECC, Calpine Energy, CNE and Direct Energy in the above-captioned Docket.

RESPECTFULLY SUBMITTED this 3rd day of February, 2017.

FENNEMORE CRAIG, P.C.

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BEFORE THE ARIZONA CORPORATION COMMISSION

In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return)	Docket No. E-01345A-16-0036
In the Matter of Fuel and Purchased Power Procurement Audits for Arizona Public Service Company)	Docket No. E-01345A-16-0123

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport-McMoRan Copper & Gold Inc.

Arizonans for Electric Choice & Competition

Calpine Energy Solutions

Constellation New Energy, Inc

Direct Energy

Cost of Service / Rate Design

February 3, 2017

DIRECT TESTIMONY OF KEVIN C. HIGGINS

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DIRECT TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. Are you the same Kevin C. Higgins who previously filed testimony on the subject of Revenue Requirements in this proceeding on behalf of Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC")?

A. Yes, I am.

Q. Are there any other parties co-sponsoring a portion of your Cost of Service/Rate Design testimony?

A. Yes. In addition to Freeport-McMoRan Copper & Gold Inc. and AECC,[1] my testimony regarding the AG-1 program is being co-sponsored by Calpine Energy Solutions, Constellation New Energy Inc, and Direct Energy.

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

OVERVIEW AND CONCLUSIONS

Q. What is the purpose of your testimony in this cost-of-service and rate design phase of the proceeding?

A. My testimony addresses APS's proposed rate spread, rate design, and cost-of-service analysis. I also address APS's Alternative Generation Experimental Rate Rider Schedule AG-1.

Q. What are the primary conclusions and recommendations presented in your testimony?

A. (1) I recommend that the Commission reject APS's proposal to terminate the successful AG-1 buy-through program. Instead, I recommend that the Commission require that AG-1 be transformed into a permanent buy-through program that would allow current AG-1 participants to continue to acquire competitively-priced generation service while also providing an opportunity for additional customers to transition to competitive pricing through an AG-2 program. The 200 MW of current AG-1 load should be treated as its own class for cost allocation purposes and not be allocated a portion of APS's generation costs in this case. To help provide a smooth transition to a permanent buy-through program, I am recommending a doubling of the Capacity Reserve Charge from 15% to 30% on current AG-1 customers for a four-year period. These revenues would be used to offset the revenue requirement for the customers who are using APS generation. Following the four-year period, this charge would step back down to 15%. I am also recommending that the current Power Supply Adjustor ("PSA") mitigation mechanism be restructured to recover a fixed $10 million per year.

In addition to the current 200 MW of AG-1 load, I recommend that another 200 MW of load be allowed to participate in a new AG-2 program. Since the new AG-2 load is currently using APS generation, I recommend that the new AG-2 load be subject to a four-year transition charge, after which the participating customers would continue to receive buy-through service with no further generation charge obligations to APS, with the exception of imbalance charges, the Management Fee, and a Capacity Reserve Charge of 15%.

I recommend that the eligibility criteria for the AG-2 program be modified from the AG-1 program to allow for broader participation. AG-1 participation is limited to customers with single-site loads of 400 kW or greater that can aggregate up to a minimum of 10 MW. For AG-2 participants, I recommend that these requirements be relaxed to allow for single-site loads of 200 kW that can aggregate up to 5 MW.

(2) APS's rate spread proposal contains a very significant subsidy of $153 million to the Residential class. I propose an approach that moves rates modestly further in the direction of cost of service, while adhering to the principle of gradualism by providing continued rate mitigation for the Residential class. My recommended rate spread at APS's requested net revenue increase of $166 million is presented in Table KCH-3-RD in my testimony. My recommended rate spread at AECC's recommended revenue requirement is presented in Table KCH-5-RD. My rate spread proposal, *including my recommendation to continue the AG-1 program*, in combination with my recommended revenue requirement adjustments, results in lower rates than APS's filed case for all rate schedules that are proposed to receive an increase by APS. Rate schedules that are proposed to

receive close to a 0.0% rate change by APS would pay essentially the same rates as recommended by APS under my rate spread and revenue requirement proposal.[2]

(3) The Average and Excess Demand method employed by APS to allocate production plant costs is a reasonable and well-accepted approach and I recommend its approval by the Commission. Further, APS's allocation of fuel-related costs based on customer class hourly load shapes and their relationship to hourly energy prices is fundamentally reasonable and I recommend Commission approval of this approach as well.

THE AG-1 PROGRAM

Q. What is the AG-1 program?

A. The AG-1 program is a retail buy-through program that was incorporated into the 2012 settlement agreement approved in APS's last rate case. This service is currently provided pursuant to Experimental Rider AG-1. The AG-1 buy-through program allows eligible customers to obtain an alternative source of generation service and utilize other existing utility pricing for ancillary services to serve their full power requirements. APS serves as the retail service provider for scheduling, transmission, and imbalance services and remains an intermediary between the customer and its generation supplier, called a Generation Service Provider ("GSP"). APS accepts delivery of the supply from the GSP and redelivers the supply to the AG-1 customer. AG-1 is available to large and extra-

[2] APS proposes that Rate E-32 XS receive a 0.04% net decrease, whereas E-32 XS receives a 0.00% net rate change in Table KCH-5-RD. Rate E-32 XS is included in the "E-32 XS, S" grouping in my testimony tables.

large commercial and industrial customers with aggregated peak load of 10 MW or more.[3] The experimental phase of AG-1was limited to 200 MW of customer load, and has been fully subscribed since inception.

AG-1 customers are exempt from APS's base generation charges, the Environmental Improvement Surcharge, and the PSA, except that the PSA Historical Component was applied for the first twelve months of service under AG-1. AG-1 customers are subject to an Administrative Management Fee of \$0.0006 per kWh, a monthly Capacity Reserve Charge applied to 15% of the customer's billed kW[4] at the Company's applicable cost-based generation rate filed at FERC, and an initial charge to keep APS whole on its fuel hedging costs.

Q. Have there been any changes to the AG-1 program since its inception?

A. Yes. There have been several changes over the course of the experimental phase of the AG-1 program.

- The pricing that APS uses for imbalance service has changed twice; initially from a Dow Jones Day-Ahead Index to an Intercontinental Exchange Day-Ahead Index and then to the Energy Imbalance Market ("EIM") Load Aggregation Point ("LAP") Price.

- The Four Corners Adjustment Surcharge was levied on AG-1 participants to pay for the Company's acquisition of SCE's share of Four Corners Generating Units 4 and 5, even though by program design these customers do not use APS's

[3] AG-1 is available to customers served under Rate Schedules E-34, E-35, E32 L, or E-32TOU L, and an aggregated group may also include accounts served under Rate Schedules E-32 M or E-32TOU M that are located on the same premises and served under the same name as an otherwise eligible customer.
[4] The Capacity Reserve Charge applies to on-peak kW for Rate Schedules E-35 and E-32TOU L.

generation fleet and have contracted separately for firm generation service elsewhere.

- The Company's applicable FERC cost-based generation rate was revised upwards by more than 32%, from \$6.985/kW to \$9.233/kW. This change occurred after the Company filed Direct Testimony and its AG-1 evaluation report in this proceeding.

Q. Are other mechanisms in place to mitigate the claimed financial impact of the AG-1 program on APS?

A. Yes. Per the settlement agreement in the last rate case, APS is allowed to mitigate the foregone margins on generation service by sharing in the wholesale margins that credit the PSA fuel expense. This crediting is based on the ratio of displaced retail sales over the total volume of short-term wholesale sales. In addition, as a result of Decision No. 75322, APS was permitted to defer for possible future recovery 90% up to \$10 million and 100% above \$10 million in unmitigated unrecovered costs resulting from the AG-1 program, after June 30, 2016 and until new rates become effective as a result of this case.[5]

Q. What does APS propose regarding the AG-1 program?

A. APS is proposing that the AG-1 program not be renewed, arguing that the program will shift unreasonable revenue responsibility to other customers. According to the Direct Testimony of Leland R. Snook, APS has incurred a financial loss on the program because the lost margins related to generation service from the program are larger than the short-term wholesale margins used to

[5] Docket No. E-01345A-11-0224, Decision No. 75322 (November 25, 2015), at 7.

mitigate the program impacts.[6] APS also attributes losses to AG-1 program participants still relying on, but not fully paying for, APS generation services, such as load following and back-up service that would be needed in the event a customer elects to return to utility service, or in the event of a failure to deliver by AG-1 suppliers. APS contends it must include AG-1 customers in its generation supply planning requirements because AG-1 customers can return to APS's generation service with six months' notice, and AG-1 customers' load is not interruptible if their generation service provider fails to deliver power.[7]

APS also cites concerns with the appropriateness of its energy imbalance charges for retail service as a reason that the AG-1 program should be discontinued.

Q. What changes does APS recommend if the Commission decides that the AG-1 program should continue?

A. APS recommends that the Capacity Reserve Charge should apply to 100% of AG-1 customers' load, rather than 15%, and that the Administrative Management Fee should be increased to at least three times the current charge of $0.0006 per kWh. APS also recommends that the energy imbalance protocol be redesigned to be suitable for retail transactions. In addition, APS recommends that program participation continue to be capped at the current level of 200 MW with a 10 MW minimum per customer, and continuation of the PSA mitigation tool.[8]

Q. What is your response to APS's proposal to eliminate the AG-1 program?

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[6] Direct Testimony of Leland R. Snook, p. 44; Attachment LRS-06DR.
[7] Attachment LRS-06DR.
[8] Direct Testimony of Leland R. Snook, pp. 44-45, Attachment LRS-06DR.

A. I recommend that the Commission reject APS's proposal to eliminate this important program. The AG-1 program has been a success. Instead of eliminating the program, I recommend that the Commission require that AG-1 be transformed into a *permanent* buy-through program that would allow current AG-1 participants to continue to acquire competitively-priced generation service while also providing an opportunity for additional customers to transition to competitive pricing through adoption of a new AG-2 program.

The AG-1 program has been fully subscribed since its inception in late 2012, demonstrating strong customer interest in this competitively-priced option. Eliminating this option would force customers who have been engaged in managing supply, risk, and cost for the past four-plus years back to monopoly-provided generation despite their clear preference for competitive alternatives. I believe it is important for Arizona's economic health to allow customers who prefer to acquire their generation service from the competitive market to be able to do so. It would certainly be a step backward to shut down a fully-subscribed market-based program for customers that have demonstrated a multi-year commitment to competitive pricing.

Q. Why do you consider the AG-1 program to be a success?

A. As I stated above, the program has been fully subscribed since its inception and it remains fully subscribed. Further, when the initially-anticipated program term was extended beyond June 30, 2016 (so that it would not expire prior to the conclusion of APS's next rate case) all participants opted to remain in the program. In APS's evaluation of the AG-1 program, the Company reported that program operations such as power scheduling, settlements, information exchanges, and billing were generally successful.[9] Moreover, the competitive suppliers selected by customers have continued to provide power to customers through the mechanics of the buy-through program, without any failures to deliver. These are the hallmarks of a successful program. Allowing customers to acquire power in the competitive market improves the economic climate for Arizona businesses as well as the competitiveness of Arizona businesses. Businesses in 18 states plus the District of Columbia have access to competitive generation.[10] Arizona businesses should have comparable opportunities. AG-1 provides that opportunity, albeit in limited form due to the participation cap and its buy-through structure.

While I believe it would be preferable to allow Arizona customers full access to the electric power marketplace to take advantage of the benefits of competition as intended by the Arizona Legislature,[11] a buy-through program such as AG-1 represents a compromise that provides commercial and industrial customers the opportunity to engage in market transactions and potentially reduce their energy costs, consistent with state policy, but without implementing full direct access service.

Q. Please describe how AG-1 should be transformed into a permanent buy-through program.

A. A permanent buy-through program is one in which the participants elect to move to competitive pricing on a permanent or long-term basis, but do so within

[9] See Direct testimony of Leland R. Snook, Attachment LRS-06DR, p. 1.
[10] Data Source: American Coalition of Competitive Energy Suppliers, State-by-State Information, http://competitiveenergy.org/consumer-tools/state-by-state-links/.
[11] Arizona Revised Statute §40-202(B) declares that "It is the public policy of this State that a competitive market shall exist in the sale of electric generation service."

the current regulatory structure and without implementing direct access. This election makes it clear that the utility should not plan for providing generation services to these customers currently or in the future. Indeed, in the case of APS, with a permanent buy-through program, the Company should, as part of its integrated resource planning process, recognize the role that this buy-through load can play in helping to defer and reduce APS's need for additional generation resources.

As I noted in my Revenue Requirement testimony, instead of eliminating the buy-through program, APS should be enlisting buy-through customers to commit to third-party procurement on a permanent or long-term basis, thereby avoiding the need for APS to procure additional generating capacity for its remaining customers. APS witness James C. Wilde indicates that APS requires 3,500 MW of new generating capacity by 2022,[12] yet APS is making no attempt to integrate or plan for the role that buy-through customers could play in deferring the need for part of that new capacity. Indeed, APS is proposing to move in the opposite direction by eliminating the AG-1 program, despite strong customer interest in retaining it.

Q. How would turning AG-1 into a permanent buy-through program impact APS's future additions to rate base?

A. One of the criticisms leveled at buy-through programs such as AG-1 is that the utility still incurs fixed generation costs to serve the departed customers. However, with the knowledge that customers in the program have permanently moved to competitive pricing and no longer require APS's generation, the

[12] Direct Testimony of James C. Wilde, p. 9.

Company could exclude that load from its planning scenarios, reducing its need for new generation resources. This would allow APS to *avoid* incurring certain new fixed generation costs.

For example, APS's Preliminary 2017 Integrated Resource Plan ("IRP") calls for 760 MW of natural gas combined-cycle generation to be added in 2020 and another 500 MW to be added in 2021.[13] These new resources would be in *addition* to the Ocotillo expansion project. Yet, in its discussion of its future generation resource needs, APS acts as if the buy-through program does not exist – even though a permanent buy-through program could delay or displace the need for this additional generation capacity. I believe this approach needs to change. It is important and in the public interest for the Commission to authorize a permanent buy-through program now so that APS can adjust its integrated resource planning to take account of the buy-through program and defer the need for new capacity additions.

Q. What if the integrated resource planning process indicates the buy-through program results in less than a MW-for-MW reduction in APS's long-term capacity needs due to reliability requirements?

A. To the extent that the integrated resource planning process indicates that the buy-through program results in less than a MW-for-MW reduction in APS's long-term capacity needs due to reliability requirements, it would reasonable to take into account the extent to which buy-through load has any genuine cost responsibility for reliability-related capacity. My proposal anticipates a continuation of the Capacity Reserve Charge at the current level of 15% after the

[13] *See* APS's Updated Preliminary 2017 IRP, Docket No. E-00000V-15-0094 (October 1, 2016), p. 23.

four-year transition period. The Capacity Reserve Charge would be an appropriate mechanism to compensate APS for any reliability-related, or must-run, generation required for buy-through load.

Q. You stated above that, as part of making the AG-1 program permanent, it should be expanded. What type of expansion do you believe is appropriate at this time?

A. I recommend that the existing 200 MW AG-1 program be retained, with the current participants granted the option to remain in the program. In addition, another 200 MW of load should be allowed to participate in a new AG-2 permanent buy-through program.

Q. Why do you believe that increasing the program size by 200 MW is appropriate?

A. It is clear that the AG-1 program has been successful. Increasing the program size by 200 MW will allow additional customers to participate, including perhaps, customers that were interested in the initial AG-1 offering in 2012, but who were not selected in the lottery that was conducted to select initial participants due to the original 200 MW cap.

Q. What is your response to APS's criticisms of the current AG-1 program?

A. APS's criticisms of the current program fall into four categories: revenue impacts on the Company, inadequate compensation for APS-supplied capacity, inadequate administrative charges, and shortcomings regarding the energy imbalance protocol.[14] I will address each in turn.

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[14] Direct Testimony of Leland R. Snook, pp. 44-45.

Q. What is your response to APS's criticism that the AG-1 program resulted in unmitigated lost revenues for APS?

A. I will address this question from both a historical perspective and a going-forward perspective. In brief, APS's claim regarding unmitigated lost revenues in the past derives in large part because APS examines the math of the AG-1 program in *isolation* rather than within the totality of APS's costs and revenues. On a *going-forward* basis, my recommendations to continue and expand the AG-1 program include changes in the treatment of fixed cost recovery that ensure APS a reasonable opportunity to recover its fixed generation costs.

Q. Please explain your contention that APS's claim regarding unmitigated lost revenues in the past from AG-1 derives in large part because the Company examines the math of the AG-1 program in isolation rather than within the totality of APS's costs and revenues.

A. The AG-1 program emerged from the 2012 settlement agreement. That agreement dealt with the *totality* of APS's costs and revenues. It is a mathematical truism that any departed customer load examined in isolation – be it from customer load reductions, customer shut downs, rooftop solar, energy efficiency, direct access, or a buy-through program – will show a revenue impact to the utility in *isolation* due to the reduction in fixed cost recovery from the customers whose status has changed. But the more relevant question from a historical perspective in this case is: How did APS actually perform financially over the historical period in question? When we examine APS's overall performance since the last general rate case we see that Pinnacle West's regulated electricity segment net income, as reported in Pinnacle West's most recent Form

10-K filing with the Securities and Exchange Commission, ranged from $405 million to $439 million in the three-year period between 2013 and 2015,[15] following Commission approval of the 2012 settlement agreement. In fact, net income increased in 2015 over the prior two years, and APS opted to delay the filing of a general rate case by 12 months relative to the earliest date allowed under the stay-out provision in the 2012 settlement agreement. The Company's financial stability during this period is likely attributable, in significant part, to the comprehensive terms of the 2012 settlement agreement, of which AG-1 was but one component.

Q. What are your recommendations concerning fixed cost recovery going forward that address the concerns raised by APS in its criticism of the AG-1 program?

A. The current AG-1 program has been in place for more than four years. Except for imbalance service, which I will discuss in greater detail below, these customers have not been using APS's generation, and under the permanent buy-through program that I am proposing, they will not use APS's generation in the future either. In fact, the continuation of this program will help APS *avoid* future generation acquisitions, reducing the future need for additional generation capacity costs for APS's remaining customers. Therefore, the 200 MW of current AG-1 load should be treated as its own class for cost allocation purposes and not be allocated a portion of APS's generation costs in this case.

Despite the strong case for not allocating any generation costs to the current AG-1 customers (who would be purchasing their generation service from

[15] Pinnacle West Capital Corporation Form 10-K for the fiscal year ended December 31, 2015, pp. 56, 58.

GSPs), in the interest of providing for a smooth transition to the permanent buy-through program, I am recommending a doubling of the Capacity Reserve Charge currently levied on these customers, from 15% to 30%, for a period of four years. These revenues would be used to offset the revenue requirement for the customers that are using APS generation. Taken in combination with a modification to the current PSA mitigation mechanism (described below) and a reasonable reduction in APS's requested revenue requirement, the AG-1 program can be transformed into a permanent buy-through program while reducing the rate impact on all customers relative to APS's filed case for the rate schedules that are proposed to receive an increase by APS.

Q. Please explain how mitigation through the PSA would work under your proposal.

A. The current PSA mitigation provision recognizes that APS is able to make additional off-system sales using the generation freed-up by the AG-1 load. The current PSA mitigation mechanism assigns a pro rata share of off-system sales margins for this purpose. This amount ranged from $7.6 million to $15.0 million between 2013 and 2015.[16] I am recommending that the current PSA mitigation be modified and restructured as a fixed $10 million per year that APS is allowed to retain rather than a floating amount. This would provide greater certainty going forward regarding the revenues produced by this mechanism.

Q. Would there be any going-forward cost deferrals associated with the continuation of the AG-1 program under your proposal?

[16] Attachment LRS-06DR, p. 4.

A. No. As my approach is designed to be fully compensatory to APS there is no reason for future cost deferrals. APS is ensured a reasonable opportunity to fully recover its fixed generation cost through a combination of: (1) my recommended increase in the Capacity Reserve Charge on AG-1 customers; (2) the restructured PSA mitigation mechanism; and (3) ensuring that all fixed costs are recovered through non-residential rate design, as I will describe in the rate spread section of my testimony. And if APS's revenue requirement is reduced to a level that is more reasonable relative to the Company's original request, my AG-1 proposal is not only fully compensatory to the Company, it results in lower rates than APS's filed case for all rate schedules that are proposed to receive an increase by APS.

Q. What is your recommended treatment of fixed generation costs for the additional 200 MW of permanent opt-out load that you are proposing as AG-2?

A. Since the new or *incremental* 200 MW of opt-out load that I am recommending is currently using APS generation, I recommend that the AG-2 opt-out load be subject to a four-year transition charge, after which the participating customers would continue to receive buy-through service with no further generation charge obligations to APS, with certain limited exceptions (discussed below). For the AG-2 buy-through load, the burden of paying for both competitive energy supply and fixed generation charges falls entirely on program participants, but in exchange, the participants are able to transition to 100% competitive pricing after four years of paying the transition charge. This approach would allow APS to reflect the load reductions from AG-2 in its long-term resource planning, just as the Company should consider the load reductions from a permanent AG-1 program.

Q. How would the transition adjustment for AG-2 load be calculated under your proposal?

A. Under my proposal, the transition adjustment for AG-2 load would be calculated as I describe below. Its structure is similar to a five-year opt-out program that is in place in the Portland General Electric ("PGE") Service territory in Oregon.

- Participating customers would not pay for APS's unbundled generation charges (inclusive of fixed generation charges and generation energy charges), the PSA,[17] and the Environmental Improvement Surcharge, but would be required to pay a transition charge for four years. The transition charge would be published prior to a 30-day enrollment period each year. For any vintage enrollment period (e.g., 2018 - 2021) the transition charge would be locked in at the outset and would apply for the duration of the transition period. At the conclusion of the transition period, participating customers would have no further transition charge obligation to APS.

- The transition charge would require the participant to pay the difference between the cost-of-service unbundled generation charges (inclusive of generation energy charges, but exclusive of generation-related riders) and the market price of power, where the market price of power and generation energy charges are projected for four years and shaped to reflect class seasonal and on-peak loads, and the market price of power is adjusted (upward) for wheeling costs

[17] A one-year payment of the PSA true-up component would be appropriate.

and line losses. For the purpose of this calculation, the fixed generation charge would be based on the unbundled generation rates in effect at the time of enrollment.

- Participating customers would continue to pay APS's unbundled distribution and transmission charges, both throughout the transition period and after the transition period is concluded.

- Imbalance charges consistent with APS's Open Access Transmission Tariff would apply when scheduled power deliveries do not match actual loads.

Q. Does your proposal for assessment of a transition charge on AG-2 load constitute an acknowledgement that APS is entitled to stranded cost recovery from shopping customers?

A. No, not at all. In Docket No. E-01345A-98-0473, et al., APS was awarded stranded cost recovery over an approximately five-year period associated with the implementation of direct access service for all customers. Accordingly, APS's stranded cost recovery was fully completed by December 31, 2004. Further, in the settlement agreement approved in Decision No. 67744, APS relinquished any future stranded cost claims associated with certain generation assets – West Phoenix CC-4, West Phoenix CC-5, Saguaro CT-3, Redhawk CC-1, and Redhawk CC-2 – that were included in rates in that case.[18] My proposal for a four-year transition charge for AG-2 load is intended to forge a middle ground that would allow expansion of the buy-through program, while allowing APS to fully recover its revenue requirement in this proceeding without affecting any non-participating customers. This compromise proposal is not intended to concede any argument

[18] See Docket No. E-01345A-03-0437, Decision No. 67744 at 9.

with respect to the termination of APS's stranded cost recovery pursuant to the Commission's order approving the settlement agreement in Docket No. E-01345A-98-0473 or Docket No. E-01345A-03-0437.

Q. What is your response to APS's criticism that the AG-1 program provides inadequate compensation for APS-supplied capacity?

A. In APS's evaluation of the AG-1 program, the Company argues that the Capacity Reserve Charge levied on AG-1 loads should be increased from 15% of customer demand to 100% if the program is continued. I note that at the time APS filed its testimony in its case, the underlying Capacity Reserve Charge was \$6.985/kW. As I discussed above, this charge has since been increased to \$9.233/kW. APS's contention that AG-1 customers should pay 100% of the former \$6.985/kW charge equates to paying 76% of the new \$9.233/kW charge.

In support of its argument, APS maintains that the Company must continue to include AG-1 customers in its generation supply planning requirements because, under the current program, AG-1 customers can return to APS's generation service with a six-month notice. APS states that this provision requires the Company to plan to accommodate this potential occurrence. APS also notes that the participating customer's load is not interruptible if the customer's supplier fails to deliver power, although the Company admits that supplier reliability has not been a problem during the four-plus-year history of the program.[19]

My proposal to transform AG-1 into a permanent buy-through program eliminates the need for APS to plan for accommodating the return of AG-1

[19] *See* APS's Response to AECC Data Request 19.1, included in Exhibit KCH-7-RD.

customers to APS generation service. Consequently, under a permanent buy-through, I see no cost basis for a Capacity Reserve Charge greater than the current 15% charge over the long-term.

Q. If you see no cost basis for setting the Capacity Reserve Charge for the existing 200 MW AG-1 load above 15% for the long term, why are you recommending increasing this charge from 15% to 30% for four years?

A. I am recommending that this charge be increased from 15% to 30% for a four-year period to help provide a smooth transition to a permanent buy-through program. These revenues would be used to offset the revenue requirement for the customers that are using APS generation. After the four-year period, the Capacity Reserve Charge would step down to the 15% charge that is in place today.

Q. Why should the Capacity Reserve Charge step down to 15% after four years?

A. The step-down is important because it is essential and reasonable for customers making a long-term commitment to competitive pricing to have a date-certain at which they are no longer required to pay APS for generation that they do not use, have not used for years, and do not plan to use in the future.

Q. Why do you believe a four-year transition period is appropriate?

A. I am recommending that a four-year transition period apply both to the doubling of the AG-1 Capacity Reserve Charge and the AG-2 transition charge because this time frame is reasonably aligned with APS's capacity expansion plans in its IRP. As I discussed above, APS's Preliminary 2017 IRP calls for 760 MW of natural gas combined-cycle generation to be added in 2020 and another 500 MW added in 2021. Heretofore, APS has failed to consider the role that a permanent buy-through program could play in displacing the need (and cost) of this new capacity. However, the Commission's adoption of a permanent buy-through program would send a strong signal to APS that a permanent buy-through program should be incorporated into the load/resource balance in the IRP. This would provide the opportunity for the permanent buy-through program to displace the need for new APS capacity additions starting in 2021. A four-year transition period would last into 2021 and would coincide with the ability of the program to displace new capacity acquisitions starting in that year.

Q. Should there be a Capacity Reserve Charge for the AG-2 load you are recommending?

A. Not during the four-year transition period, as the AG-2 load will effectively be paying for 100% of APS's fixed generation charges, even though the participants would be acquiring their generation product from another source. This large expense more than compensates the Company for generation reserves that otherwise would be appropriate for a program without transition charges. At the conclusion of the transition period, AG-2 customers would be subject to the same 15% Capacity Reserve Charge that is in place today.

Q. What is your response to APS's criticism that the management fee charged to the AG-1 program is inadequate?

A. APS argues that the \$0.0006/kWh management fee is inadequate to cover AG-1 program incremental costs. Mr. Snook states that if the program is continued, this fee should be increased to at least three times the current charge to cover the actual cost of administration.[20]

To the extent that an increase in the management fee is cost-justified, I do not oppose an increase. However, the \$0.0018/kWh suggested by Mr. Snook for the existing 200-MW AG-1 load appears to be excessive. Instead, I believe that a doubling of the charge to \$0.0012/kWh is more reasonable. This change would further increase the charges to AG-1 customers by around \$630,000. However, I do not believe this fee should be charged to the AG-2 load that is subject to the transition adjustment, given that these customers would be paying for 100% of APS's fixed generation charges during the transition period. At the conclusion of the transition period, the instatement of the management fee would be appropriate.

Q. What is your response to APS's criticism regarding the alleged shortcomings of the energy imbalance protocol?

A. APS's criticism of the energy imbalance protocol is related to the Company's discussion of load following. Over the course of a day, month, and year, a customer's load will vary. APS characterizes the current situation as one in which generation suppliers often do not attempt to match their supply schedules with expected hourly deviations in customer loads, but rather rely on standard trading blocks that do not vary hour by hour, except perhaps for on-peak and off-peak periods. As a result, the load following is performed by APS's units. APS is compensated for this service through the energy imbalance charge. However,

[20] Direct Testimony of Leland R. Snook, p. 45.

APS indicates that the current imbalance charge is designed for wholesale transactions; APS claims that charge is inadequate for retail service.

In response, it is important to first note that APS provides no explanation as to what makes the imbalance protocols inappropriate for AG-1 load. It is equally important to note that there has been a major change in APS's imbalance service since the time APS prepared its AG-1 evaluation and filed its direct testimony in this case. Specifically, imbalance service is no longer being provided directly by APS, but rather through the EIM operated by the California Independent System Operator ("CAISO"). In light of this important change, APS's claim that it is providing load following to AG-1 load is substantially weakened, as the the EIM dispatch protocols now provide that function. Indeed, the imbalance charges that current AG-1 customers must pay are now derived from EIM clearing prices, as formulated pursuant to the EIM tariff provisions.

Under the EIM protocols, parties whose hourly demand deviates from their scheduled power delivery must pay a real-time market price for the imbalance, rather than a day-ahead index price previously charged under the APS imbalance protocol. The EIM imbalance price is a locational marginal price which FERC has found to be "an adequate inducement for the customer to act in accordance to market rules."[21] Arguably, the EIM represents the state of the art in the western United States for providing imbalance service. Using the EIM to price AG-1 imbalance service under the current arrangement sends the proper

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[21] APS EIM Order, 155 FERC ¶ 61,112 at p. 40 (2016).

price signals to GSPs for scheduling their loads, which I believe addresses the concerns raised by APS in its AG-1 evaluation.

In addition, it is important to point out that APS remains the transmission provider for AG-1 customers and the AG-1 program guidelines require pre-scheduling 3-4 hours in advance of normal day-ahead scheduling deadlines. This "locks in" the AG-1 customer's hourly schedule almost a full day in advance. This is done to accommodate APS, which schedules the energy to the AG-1 customer. As a consequence, AG-1 suppliers are unable to avail themselves of hourly trading tools. So to a certain extent, some of the shortcomings that APS perceives with the current arrangement were "designed in" by APS from the outset. If APS believes that its own guidelines are causing AG-1 participants to over-rely on the energy imbalance service provided within the program, one option may be to work with GSP and AG-1 customers to determine if the rigidity of the AG-1 scheduling process could be modified to allow the AG-1 suppliers greater flexibility in the scheduling process. Indeed, the Company's participation in the EIM may provide an opportunity for greater flexibility.

Q. Are there any other program design changes that you are recommending?

A. Yes. In conjunction with making AG-1 a permanent buy-through program, I am recommending that AG-1 and AG-2 participants be prohibited from returning to cost-based rates without a minimum of three years' notice. This is the same notice provision in the PGE program. The PGE program has been in place since 2003, and to date, no five-year opt-out customer has sought to return to cost-based rates.

In addition, I recommend that eligibility for the AG-2 program be modified to allow for a somewhat broader participation. Currently, participation is limited to customers with single-site loads of 400 kW or greater that can aggregate up to a minimum of 10 MW. For AG-2 load, I recommend that these requirements be reduced to allow for single-site loads of 200 kW that can aggregate up to 5 MW.

Q. Please summarize your recommendations concerning the continuation and expansion of AG-1 service.

A. I recommend that the Commission require that AG-1 be transformed into a *permanent* buy-through program that would allow current AG-1 participants to continue to acquire competitively-priced generation service while also providing an opportunity for additional customers to transition to competitive pricing through an AG-2 program. The 200 MW of current AG-1 load should be treated as its own class for cost allocation purposes and not be allocated a portion of APS's generation costs in this case. APS would be ensured a reasonable opportunity to fully recover its fixed generation costs in part through a doubling of the Capacity Reserve Charge from 15% to 30% on current AG-1 customers for a four-year period, and a restructured PSA mitigation mechanism set at $10 million per year.

In addition to the current 200 MW of AG-1 load, I recommend that another 200 MW of permanent buy-through load (AG-2) should be allowed to participate in a new AG-2 program. Since the AG-2 load is currently using APS generation, I recommend that the AG-2 load be subject to a four-year transition charge, after which the participating customers would continue to receive buy-through service with no further generation charge obligations to APS, with certain limited exceptions. The AG-2 load would not be subject to the Capacity Reserve Charge during the transition period. At the conclusion of the transition period, AG-2 customers would be subject to the same 15% Capacity Reserve Charge that is in place today.

I recommend that eligibility for the AG-2 tranche be modified to allow for a somewhat broader participation. Currently, participation is limited to customers with single-site loads of 400 kW or greater that can aggregate up to a minimum of 10 MW. For AG-2 participants, I recommend that these requirements be reduced to allow for single-site loads of 200 kW that can aggregate up to 5 MW.

To the extent that an increase in the management fee is cost-justified, I do not oppose an increase to around \$0.0012/kWh for the existing 200-MW AG-1 load. However, I do not believe this fee should be charged to the AG-2 load, given that these customers would effectively be paying for 100% of APS's fixed generation charges during the transition period. At the conclusion of the transition period, the instatement of the management fee would be appropriate.

RATE SPREAD

Q. What general guidelines should be employed in spreading any change in rates?

A. In determining rate spread, or revenue allocation, it is important to align rates with cost causation, to the greatest extent practicable. Properly aligning rates with the costs caused by each customer group is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for customer groups that would experience significant rate increases from doing so. This principle of ratemaking is known as "gradualism." When employing this principle, it is important to adopt a long-term strategy of moving in the direction of cost causation, and to avoid schemes that result in permanent cross-subsidies from other customers.

Q. What has APS proposed with respect to rate spread?

A. APS's proposed rate spread is discussed by APS witness Charles A. Miessner.[22] APS's proposed spread of its net $166 million increase is presented in Exhibit KCH-1-RD and summarized in Table KCH-1-RD, below.

[22] Mr. Miessner's Attachment CAM-2DR summarizes APS's proposed rate spread.

Table KCH-1-RD

APS Proposed Rate Change
Combined Impact of Base Rates and Rider Resets

	Present Revenue	Proposed Revenue	Rider Transfer	Net Revenue Change	Percent Change
Residential	1,486,578	1,773,473	168,607	118,288	7.96%
General Service					
E-20	4,069	4,896	461	367	9.01%
E-30, 32 (total)	1,124,607	1,238,545	83,279	30,660	2.73%
E-30	1,206	1,310	55	50	4.11%
E-32 XS, S	510,248	554,195	43,816	131	0.03%
E-32 M	308,825	344,902	23,705	12,372	4.01%
E-32 L	272,178	302,474	13,789	16,507	6.06%
E-32 TOU	32,150	35,664	1,914	1,600	4.98%
Schools	11,345	13,090	1,060	685	6.04%
E-34	59,842	67,504	3,186	4,476	7.48%
E-35	143,235	157,590	6,362	7,993	5.58%
E-36 M	829	952	61	62	7.42%
Water Pumping	28,739	33,631	3,243	1,649	5.74%
Street Lighting	21,082	23,212	979	1,151	5.46%
Dusk-to-Dawn	8,578	9,445	313	554	6.46%
Total	2,888,903	3,322,337	267,551	165,883	5.74%

Q. What is your assessment of APS's rate spread proposal?

A. APS's rate spread proposal contains a very significant subsidy of $153 million to the Residential class.[23] This can be seen by comparing the Company's proposed base revenues for the residential class summarized in Table KCH-1-RD to the allocation of costs to the residential class at an equalized rate of return shown in Workbook C - 2015TY COSS Working Model.[24] This subsidy amounts to 8.6% of APS's proposed residential base rates.[25] At the same time, the General Service class is *paying* a subsidy of $153 million under APS's proposal. While I do not object to employing the principle of gradualism to rate spread in this case, I believe some adjustments should be made to move rates closer to cost.

[23] $1,926,207,779 - $1,773,473,749 = $152,734,030.
[24] Workbook C - 2015TY COSS Working Model, "COS – Summary of Results" tab, line 58.
[25] Calculation: $152,734,030 /$1,773,473,749 = 8.612%.

Q. Do you have an alternative rate spread recommendation?

A. Yes. I propose an approach that moves rates further in the direction of cost of service, while adhering to the principle of gradualism by providing continued rate mitigation for the Residential class. Although the Residential class warrants a net rate increase of 18.2%[26] at APS's requested revenue requirement, the Company recommends a Residential increase that is just 2.22% above the 5.74% system average increase, resulting in a net increase of 7.96%.[27] Instead, I recommend capping the Residential increase at 4.00% above the system average increase and using the difference to reduce the subsidies paid by the subsidy-paying rate schedules in the General Service class. At APS's proposed revenue requirement, this would result in a Residential increase of 9.74%. While this modest movement in the direction of cost would reduce the intra-class subsidies, a subsidy of $126 million to Residential customers would remain. As I show later in my testimony, at a lower revenue requirement, this 4.00% cap could be reduced.

Q. What is the effect of your proposed change to APS's recommended rate spread?

A. The impact of my recommended change to APS's rate spread is presented in Exhibit KCH-2-RD and is summarized in Table KCH-2-RD below. Note that I have prepared Exhibit KCH-2-RD and Table KCH-2-RD to be directly comparable to APS's proposed spread of its requested $166 million rate increase

[26] The increase of 18.2% is the net revenue increase divided by current base revenue only, consistent with Attachment CAM-2DR. If adjustor transfer revenue were included in the denominator, the required increase would be 16.4%.

[27] APS calculates its net increase percentages presented in Attachment CAM-2DR by dividing the net revenue increase including the adjustor transfers by current base revenue only. If the denominators included adjustor transfer revenue these percentages would be lower.

and these presentations do not incorporate my proposed continuation of the AG-1 program.

Table KCH-2-RD

AECC Proposed Changes to APS Rate Spread
Combined Impact of Base Rates and Rider Resets
at APS's Proposed $166 Million Net Revenue Increase

(Assumes Discontinuation of AG-1 per APS's Proposal)

	Present Revenue	Proposed Revenue	Rider Transfer	Net Revenue Change	Percent Change
Residential	1,486,578	1,800,009	168,607	144,824	9.74%
General Service					
E-20	4,069	4,896	461	367	9.01%
E-30, 32 (total)	1,124,607	1,212,009	83,279	4,124	0.37%
E-30	1,206	1,281	55	20	1.70%
E-32 TOU	32,150	34,893	1,914	829	2.58%
E-32 XS, S	510,248	541,911	43,816	(12,153)	-2.38%
E-32 M	308,825	337,347	23,705	4,817	1.56%
E-32 L	272,178	296,577	13,789	10,610	3.90%
Schools	11,345	13,090	1,060	685	6.04%
E-34	59,842	67,504	3,186	4,476	7.48%
E-35	143,235	157,590	6,362	7,993	5.58%
E-36 M	829	952	61	62	7.42%
Water Pumping	28,739	33,631	3,243	1,649	5.74%
Street Lighting	21,082	23,212	979	1,151	5.46%
Dusk-to-Dawn	8,578	9,445	313	554	6.46%
Total	2,888,903	3,322,337	267,551	165,883	5.74%

Q. Have you calculated the rate spread that results from continuing the AG-1 program as you recommend previously in your testimony?

A. Yes, I have. In its rate case filing, APS has assumed the termination of the AG-1 program. Consequently APS has allocated generation costs to these customers, even though these customers generally do not use APS generation services.[28] As I discussed above, under the permanent buy-through program I am proposing, AG-1 customers generally will not use APS's generation in the future

[28] As I discussed above, although AG-1customers used APS imbalance service in the past, the Company has transferred operations of its imbalance service to the EIM.

either and indeed should help APS *avoid* future generation acquisitions, reducing the future need for additional generation capacity acquisitions for all remaining generation customers. Therefore, the 200 MW of current AG-1 load should be treated as its own class for cost allocation purposes and not be allocated a portion of APS's generation costs in this case.

I present my recommended rate spread at APS's requested net revenue requirement increase *and* my proposal to retain the AG-1 program in Exhibit KCH-4-RD. These results are summarized in Table KCH-3-RD below. This rate spread includes the effects of my recommendation to double the Capacity Reserve Charge from 15% to 30% on current AG-1 customers (for a four-year period) as well as my \$10 million PSA mitigation proposal.[29] To ensure that APS has an opportunity for full fixed cost recovery, I have reduced the net rate decrease that would have otherwise accrued to any non-residential customer classes in Table KCH-2-RD sufficient to recover the target revenue requirement.

[29] My assignment of costs to AG-1 is presented in Exhibit KCH-3-RD.

Table KCH-3-RD

AECC Proposed Changes to APS Rate Spread
Combined Impact of Base Rates and Rider Reset
at APS's Proposed $166 Million Net Revenue Increase

(Assumes Continuation of AG-1 per AECC Proposal)

	Present Revenue	Proposed Revenue	Rider Transfer	Net Revenue Change	Percent Change
Residential	1,486,578	1,800,009	168,607	144,824	9.74%
General Service					
E-20	4,069	4,896	461	367	9.01%
E-30, 32 (total)	1,087,208	1,182,101	81,926	12,968	1.19%
E-30	1,206	1,281	55	20	1.70%
E-32 TOU	31,323	34,116	1,896	897	2.86%
E-32 XS, S	510,248	553,294	43,816	(770)	-0.15%
E-32 M	305,191	333,263	23,581	4,491	1.47%
E-32 L	239,240	260,146	12,578	8,328	3.48%
Schools	11,345	13,090	1,060	685	6.04%
E-34	50,469	56,720	2,842	3,409	6.75%
E-35	114,279	125,744	5,482	5,983	5.24%
AG-1	75,728	62,538	2,577	(15,767)	-20.82%
E-36 M	829	952	61	62	7.42%
Water Pumping	28,739	33,631	3,243	1,649	5.74%
Street Lighting	21,082	23,212	979	1,151	5.46%
Dusk-to-Dawn	8,578	9,445	313	554	6.46%
Sub-Total	2,888,903	3,312,337	267,551	155,883	5.40%
PSA AG-1 Rev.				10,000	
Total	2,888,903	3,312,337	267,551	165,883	5.74%

Q. Table KCH-3-RD shows an apparent rate reduction for AG-1 even though you are recommending an increase in the Capacity Reserve Charge. Can you explain this seeming contradiction?

A. Under my proposal AG-1 rates are <u>not</u> decreasing, but are significantly increasing compared to current rates due to the doubling of the Capacity Reserve Charge and increase in the Management Fee. The negative entry does not represent a rate decrease for AG-1 but rather represents the removal of the AG-1 generation revenue requirement (net of the Capacity Reserve Charge) from APS's filed case. This adjustment is necessary because APS assumed that the program would be terminated; consequently, the Company assigned new generation revenue requirement to these customers. The negative entry for AG-1 in Table KCH-3-RD (and the subsequent tables in my testimony) simply reverses this APS adjustment. Indeed, in addition to paying more for the Capacity Reserve Charge under my proposal, AG-1 customers must also procure the entirety of their generation service in the competitive market. These latter costs are not shown in any of my tables.

Q. What approach to rate spread should be adopted if the Company's requested revenue requirement is reduced by the Commission?

A. If the Company's requested rate increase is reduced by the Commission, I recommend that each class's allocated base revenue be reduced proportionately.

Q. Do you have an example to illustrate how your approach would work?

A. Yes. I have prepared an example using a reduction in revenue requirement of $81.3 million from APS's filed case, which reflects AECC's recommended revenue requirement adjustments presented in my Revenue Requirement testimony. This calculation is presented in Exhibit KCH-5-RD and is summarized in Table KCH-4-RD, below. To make this calculation, I first determined each class's share of base revenue requirement in Table KCH-3-RD, above, which is my proposed rate spread at APS's proposed revenue requirement (including continuation of AG-1). Next, I assume that the Commission reduces APS's proposed revenue increase by $81.3 million, as I recommended in my Revenue Requirement testimony. The resulting rate spread is then calculated by holding each class's share of base revenues constant between the two cases. I describe this result as a "tentative" rate spread, because it is subject to one final adjustment described below.

Table KCH-4-RD

AECC "Tentative" Rate Spread
Combined Impact of Base Rates and Rider Reset
At AECC's Proposed Revenue Requirement
(\$81.3 Million Revenue Reduction to APS's Revenue Proposal)

(Assumes Continuation of AG-1 per AECC Proposal and Permits Net Reductions)

	Present Revenue	Proposed Revenue	Rider Transfer	Net Revenue Change	Percent Change
Residential	1,486,578	1,755,295	168,607	100,110	6.73%
General Service					
E-20	4,069	4,774	461	245	6.02%
E-30, 32 (total)	1,087,208	1,152,737	81,926	(16,397)	-1.51%
E-30	1,206	1,249	55	(11)	-0.94%
E-32 TOU	31,323	33,269	1,896	50	0.16%
E-32 XS, S	510,248	539,550	43,816	(14,514)	-2.84%
E-32 M	305,191	324,985	23,581	(3,787)	-1.24%
E-32 L	239,240	253,684	12,578	1,866	0.78%
Schools	11,345	12,765	1,060	360	3.17%
E-34	50,469	55,311	2,842	2,000	3.96%
E-35	114,279	122,620	5,482	2,859	2.50%
AG-1	75,728	61,933	2,577	(16,372)	-21.62%
E-36 M	829	928	61	38	4.57%
Water Pumping	28,739	32,796	3,243	814	2.83%
Street Lighting	21,082	22,635	979	574	2.72%
Dusk-to-Dawn	8,578	9,210	313	319	3.72%
Sub-Total	2,888,903	3,231,004	267,551	74,550	2.58%
PSA AG-1 Rev.				10,000	
Total	2,888,903	3,231,004	267,551	84,550	2.93%

As shown in Table KCH-4-RD, using this revenue apportionment approach results in each rate schedule retaining its basic relationship to the system average increase as occurs in the initial spread at APS's proposed revenue requirement; for instance, the Residential class remains within 4 percentage points of the system average increase. Table KCH-4-RD also demonstrates that my tentative rate spread proposal, including my recommendation to continue the AG-

1 program, in combination with my recommended revenue requirement, results in all rate schedules having lower rates than under APS's filed case. This can be seen by comparing the percentage rate increases in Table KCH-4-RD to the comparable column in Table KCH-1-RD.

Q. Table KCH-4-RD shows several rate schedules receiving rate reductions even though the overall revenue requirement is increasing. Have you prepared an alternative rate spread proposal in the event the Commission does not allow for any rate reductions?

A. Yes. Even though I believe there are instances in which it is appropriate to allow the rates of certain classes to be decreased, I recognize that the Commission may be reluctant to do so when overall rates are increasing. In the event the Commission does not allow for any rate reductions, I have prepared an alternative rate spread proposal at AECC's recommended revenue requirement in Table KCH-5-RD, below.[30]

[30] As I discussed above, the negative entry for AG-1 does not represent a rate decrease for this group, but is simply the reversal of APS's inclusion of a new generation revenue requirement for these customers under the assumption that the program would be terminated.

Table KCH-5-RD

AECC Proposed Rate Spread
Combined Impact of Base Rates and Rider Reset
At AECC's Proposed Revenue Requirement
($81.3 Million Revenue Reduction to APS's Revenue Proposal)

(Assumes Continuation of AG-1 per AECC Proposal and No Net Rate Reductions)

	Present Revenue	Proposed Revenue	Rider Transfer	Net Revenue Change	Percent Change
Residential	1,486,578	1,741,021	168,607	85,836	5.77%
General Service					
E-20	4,069	4,736	461	206	5.06%
E-30, 32 (total)	1,087,208	1,169,134	81,926	0	0.00%
E-30	1,206	1,261	55	0	0.00%
E-32 TOU	31,323	33,219	1,896	0	0.00%
E-32 XS, S	510,248	554,064	43,816	0	0.00%
E-32 M	305,191	328,772	23,581	0	0.00%
E-32 L	239,240	251,818	12,578	0	0.00%
Schools	11,345	12,661	1,060	256	2.26%
E-34	50,469	54,861	2,842	1,550	3.07%
E-35	114,279	121,623	5,482	1,862	1.63%
AG-1	75,728	61,933	2,577	(16,372)	-21.62%
E-36 M	829	920	61	30	3.66%
Water Pumping	28,739	32,529	3,243	547	1.90%
Street Lighting	21,082	22,451	979	390	1.85%
Dusk-to-Dawn	8,578	9,135	313	244	2.85%
Sub-Total	2,888,903	3,231,004	267,551	74,550	2.58%
PSA AG-1 Rev.				10,000	
Total	2,888,903	3,231,004	267,551	84,550	2.93%

Q. Which rate spread are you ultimately proposing at AECC's recommended revenue requirement?

A. While I believe that the rate spreads in both Tables KCH-4-RD and KCH-5-RD are reasonable, I am recommending ultimate adoption of the rate spread in Table KCH-5-RD because this provides for greater mitigation for those customer classes experiencing a rate increase.

Table KCH-5-RD shows that my ultimate rate spread proposal, including my recommendation to continue the AG-1 program, in combination with my recommended revenue requirement, results in lower rates than APS's filed case for all rate schedules that are proposed to receive an increase by APS. Rate schedules that are proposed to receive close to a 0.0% rate change by APS would pay essentially the same rates as recommended by APS under my rate spread and revenue requirement proposal.[31]

Q. Have you reviewed APS's proposal for recovering the AG-1 cost deferral that was approved in Decision No. 75322?

A. Yes, I have. APS proposes to amortize these costs over five years from non-residential customers.

Q. Do you agree with APS's approach to recovering the AG-1 deferral?

A. Yes, I do. The deferral resulted when APS refrained from filing a rate case as early as the Company could have under the terms of the 2012 settlement agreement. The initial AG-1 tariff provided that the program would be available for four years from the effective date of AG-1, unless extended by the Commission. Absent Commission action, this would have resulted in program termination on June 30, 2016. However, it was always anticipated that the AG-1 program was going to be evaluated in the next rate case following that settlement agreement. Subsequently, when APS's rate case filing was delayed beyond the initially-anticipated filing date, the Commission agreed to extend the AG-1 program to match the timing of the later filing, subject to a deferral of a portion of APS costs. As all customers benefitted from the extended rate case stay-out, it is

[31] APS proposes that Rate E-32 XS receive a 0.04% net decrease, whereas E-32 XS receives a 0.00% net rate change in Table KCH-5-RD. Rate E-32 XS is included in the "E-32 XS, S" grouping in my testimony tables.

reasonable for the deferral that resulted from the extension of AG-1 to be recovered as proposed in APS's filing.

MISCELLANEOUS NON-RESIDENTIAL RATE DESIGN MATTERS

Voltage Differentiation

Q. Is APS's rate design for non-residential customers differentiated by service voltage level?

A. Yes. Different basic service charges and demand charges are applied to secondary, primary, and transmission service voltage levels. For example, the unbundled Delivery Charges applicable to E-35 transmission voltage service are significantly lower than those applicable to secondary and primary voltage service, reflecting the very limited use of the distribution system by transmission voltage customers.

Q. Do you believe it is appropriate to offer rates designed for transmission voltage customers?

A. Yes. It is appropriate to exclude the vast majority of distribution-related costs from the calculation of rates for transmission voltage customers because such customers only utilize the distribution system to a minimal extent. I note that APS's rate design appropriately reflects this cost-based differentiation for Rate E-35. This differential should be carried forward and reflected in the final rate design approved in this case at the final approved APS revenue requirement.

Aggregation Discount

Q. What has APS proposed regarding an aggregation discount?

A. As explained in Mr. Miessner's Direct Testimony, APS is proposing to recognize a generation aggregation discount applied to the unbundled generation rates for qualifying customers on Rates E-32 and E-32TOU-L.[32]

Q. Do you believe that such a discount is reasonable?

A. Yes. Unlike distribution service, the cost of providing generation service to a retail customer is not a function of the number of sites over which the customer's load is dispersed, but a function of its aggregate size and load characteristics, such as its overall load factor. The aggregation discount proposed by APS attempts to price unbundled generation for a qualifying customer's aggregated load on the same basis as a comparably-sized single-site customer. I believe this is a reasonable proposition and should be adopted.

COST OF SERVICE

Q. What is the purpose of cost-of-service analysis?

A. Cost-of-service analysis is conducted to assist in determining appropriate rates for each customer class. It involves the assignment of revenues, expenses, and rate base to each customer class, and includes the following steps:

- *Separating* the utility's costs in accordance with the various *functions* of its system (e.g., generation [or production], transmission, distribution);
- *Classifying* the utility's costs with respect to the manner in which they are incurred by customers (e.g., customer-related costs, demand-related costs, and energy-related costs); and

[32] Direct Testimony of Charles Miessner, p. 53.

- *Allocating* responsibility for the utility's costs to the various customer classes based on principles of cost causation.

Q. What is the role of cost-of-service analysis in setting rates?

A. Each of the three steps above has an important role in the ratemaking process. Cost functionalization guides classification and allocation method selection based on the utility function served. If rates are unbundled by function, as they are required to be in Arizona, then separating the utility's costs by function also determines the generation-related, transmission-related, and distribution-related components of unbundled rates.

The classification of costs informs the selection of allocation methods, i.e., demand, energy, or customer-based. The classification of costs is also critical to the rate design process, i.e., in determining the proper customer charge, demand charge, and energy charge for each rate schedule.

Finally, the allocation of costs to customer classes guides the revenue allocation across customer classes, commonly referred to as "rate spread." In determining rate spread, it is important to align rates with cost causation to the greatest extent practicable. Properly aligning rates with the costs caused by each customer class is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

Q. What approach has APS used for allocating generation plant costs between APS retail customers and FERC-jurisdictional customers?

A. As explained in the direct testimony of Mr. Snook,[33] APS uses the 4-Coincident Peaks ("4CP") method for allocating generation plant costs between its state and federal jurisdictional loads. The 4CP method allocates fixed production costs based on the average of system peak demands in the four summer months, which is when APS's production capacity requirements are determined.

Q. In your opinion, is the 4CP method appropriate for allocating APS's jurisdictional generation plant costs?

A. Yes, it is. APS's maximum system demands are driven by summer usage. Given the characteristics of APS's system, the 4CP method properly aligns the allocation of the Company's fixed costs with cost causation. As noted by Mr. Snook, the 4CP method is used by APS in its cases before FERC.

Q. Does APS also use the 4CP method for allocating generation plant costs across its retail customer classes in this case?

A. No. APS uses the Average and Excess Demand method for that purpose. This method was used in APS's previous two rate cases and was adopted in response to the directives and guidance from the Commission in Decision No. 69633 in Docket No. E-01345A-05-0816.[34]

Q. Do you agree with APS's use of the Average and Excess Demand method for allocating the cost of production plant among customer classes?

A. Yes, I do. The Average and Excess Demand method is described in the NARUC Manual in its section entitled "Energy Weighting Methods" and fully

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[33] Direct Testimony of Leland R. Snook, p. 22.
[34] *See* Decision at 70-71.

meets the Commission's stated objective in Decision No. 69663 with respect to allocating a portion of production plant based on energy. As stated in the NARUC Manual, this method "effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor."[35]

Q. How does the Average and Excess Demand method apportion responsibility for incremental production plant that is required to meet loads that are above average demand?

A. The Average and Excess Demand method allocates the cost of capacity above average demand in proportion to each class's excess demand, where excess demand is measured as the difference between each class's individual peak demand[36] and its average demand. In this manner, the incremental amount of production plant that is required to meet loads that are above average demand is properly allocated to the classes who create the need for the additional capacity.

Q. Is the Average and Excess Demand method used in any neighboring jurisdictions?

A. Yes. The Average and Excess Demand method is also used by UNS Electric, Inc., while variants of this method are utilized by Tucson Electric Power Company and other electric utilities in the neighboring states of New Mexico, Colorado, and Texas.

Q. How does APS allocate fuel-related costs across customer classes?

[35] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.
[36] A class's individual peak demand is often referred to as "Class Non-Coincident Peak Demand" or "Class NCP."

A. APS allocates fuel-related costs based on customer class hourly load shapes and their relationship to hourly energy prices, which produces a weighted energy cost for each class.

Q. Do you support APS's allocation method for fuel-related costs?

A. Yes. This method properly aligns cost responsibility with cost causation, and therefore is inherently equitable. APS's use of the weighted energy allocator for fuel costs encourages efficiency in resource utilization through good price signals.

Q. What is your overall recommendation concerning APS's production cost-of-service methods in this proceeding?

A. For the reasons discussed above, I recommend that the Average and Excess Demand method and the Company's allocation of fuel-related expenses be approved by the Commission.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APS Proposed Rate Change
Combined Impact of Base Rates and Rider Resets

	(a)	(b)	(c)	(d)	(e)	(f) = (g) - (e)	(g)	(h) = (d) ÷ (b)
Line No.	**Rate Class/Schedule**	**Current Proforma Base Revenue (\$000)[1]**	**Transfer of Rider Revenue (\$000)[2]**	**APS Proposed Net Revenue Increase (\$000)[1]**	**APS Proposed Proforma Base Fuel + Other Var. Revenue (\$000)[3]**	**APS Proposed Proforma Base Non-Fuel Revenue (\$000)**	**APS Proposed Proforma Base Revenue (\$000)[1]**	**APS Net Base % Change vs Base**
1	Residential	1,486,578	168,607	118,288	415,738	1,357,735	1,773,473	7.96%
2	General Service							
3	E-20	4,069	461	367	1,167	3,729	4,896	9.01%
4	E-30	1,206	55	50	157	1,153	1,310	4.11%
5	E-32 XS	210,347	18,198	(82)	46,154	182,309	228,463	-0.04%
6	E-32 XS Solar Legacy	802	69	0	135	736	871	0.00%
7	E-32TOU XS	792	65	3	184	676	860	0.38%
8	E-32 S	299,099	25,549	213	80,137	244,724	324,861	0.07%
9	E-32TOU S	3,376	269	22	955	2,712	3,667	0.65%
10	E-32 M Total	308,825	23,705	12,372	98,592	246,310	344,902	4.01%
11	E-32TOU M	6,774	483	309	2,210	5,356	7,566	4.56%
12	GS-S M	5,421	488	348	1,446	4,810	6,257	6.41%
13	GS-S L	5,924	572	338	1,862	4,971	6,834	5.70%
14	E-32 L Total	272,178	13,789	16,507	100,544	201,930	302,474	6.06%
15	E-32TOU L Total	21,208	1,097	1,266	7,821	15,750	23,571	5.97%
16	E-30, E-32 Subtotal	1,135,952	84,339	31,345	340,198	911,437	1,251,635	2.76%
17	E-34 Total	59,842	3,186	4,476	25,844	41,659	67,504	7.48%
18	E-35 Total	143,235	6,362	7,993	69,132	88,458	157,590	5.58%
19	E-36 M	829	61	62	267	684	952	7.42%
20	Total General Service	1,343,926	94,409	44,241	436,608	1,045,968	1,482,576	3.29%
21	Irrigation	28,739	3,243	1,649	10,357	23,274	33,631	5.74%
22	Outdoor/Street Lighting	21,082	979	1,151	4,707	18,505	23,212	5.46%
23	Dusk to Dawn Lighting	8,578	313	554	713	8,732	9,445	6.46%
24	Total	2,888,903	267,551	165,883	868,123	2,454,214	3,322,337	5.74%

1. Data Source: APS Standard Filing Requirement Schedule H-2 with APS's E-34/E-35 correction provided in APS's Response to Staff Data Request 10.3.
2. Data Source: APS Witness Charles A Miessner Workpaper 01DR.
3. Derived by multiplying APS's as-filed proforma base fuel cost of \$0.029882/kWh (APS Attach. PME-04DR, p.2) and other variable costs of \$0.001105/kWh (APS PME-WP26DR) times proforma class kWh energy (APS CAM-WP01DR).

AECC Proposed Changes to APS Rate Spread
Combined Impact of Base Rates and Rider Resets
at APS's Proposed $166 Million Net Revenue Increase

(Assumes Discontinuation of AG-1 per APS's Proposal)

	(a)	(b)	(c)	(d)	(e)	(f) = (g) - (e)	(g)	(h) = (d) ÷ (b)
Line No.	Rate Class/Schedule	Current Proforma Base Revenue ($000)[1]	Transfer of Rider Revenue ($000)[2]	AECC Proposed Net Revenue Increase ($000)	APS Proposed Proforma Base Fuel + Other Var. Revenue ($000)[3]	AECC Proposed Proforma Base Non-Fuel Revenue ($000)	AECC Proposed Proforma Base Revenue ($000)	AECC Net Base % Change vs Base
1	Residential	1,486,578	168,607	144,824	415,738	1,384,270	1,800,009	9.74%
2	General Service							
3	E-20	4,069	461	367	1,167	3,729	4,896	9.01%
4	E-30	1,206	55	20	157	1,123	1,281	1.70%
5	E-32 XS	210,347	18,198	(5,146)	46,154	177,245	223,399	-2.45%
6	E-32 XS Solar Legacy	802	69	(19)	135	717	852	-2.41%
7	E-32TOU XS	792	65	(16)	184	657	841	-2.03%
8	E-32 S	299,099	25,549	(6,988)	80,137	237,523	317,660	-2.34%
9	E-32TOU S	3,376	269	(59)	955	2,631	3,586	-1.76%
10	E-32 M Total	308,825	23,705	4,817	98,592	238,755	337,347	1.56%
11	E-32TOU M	6,774	483	141	2,210	5,189	7,398	2.09%
12	GS-S M	5,421	488	348	1,446	4,810	6,257	6.41%
13	GS-S L	5,924	572	338	1,862	4,971	6,834	5.70%
14	E-32 L Total	272,178	13,789	10,610	100,544	196,032	296,577	3.90%
15	E-32TOU L Total	21,208	1,097	764	7,821	15,248	23,069	3.60%
16	E-30, E-32 Subtotal	1,135,952	84,339	4,809	340,198	884,901	1,225,099	0.42%
17	E-34 Total	59,842	3,186	4,476	25,844	41,659	67,504	7.48%
18	E-35 Total	143,235	6,362	7,993	69,132	88,458	157,590	5.58%
19	E-36 M	829	61	62	267	684	952	7.42%
20	Total General Service	1,343,926	94,409	17,705	436,608	1,019,432	1,456,040	1.32%
21	Irrigation	28,739	3,243	1,649	10,357	23,274	33,631	5.74%
22	Outdoor/Street Lighting	21,082	979	1,151	4,707	18,505	23,212	5.46%
23	Dusk to Dawn Lighting	8,578	313	554	713	8,732	9,445	6.46%
24	Total	2,888,903	267,551	165,883	868,123	2,454,214	3,322,337	5.74%

1. Data Source: APS Standard Filing Requirement Schedule H-2 with APS's E-34/E-35 correction provided in APS's Response to Staff Data Request 10.3.
2. Data Source: APS Witness Charles A Miessner Workpaper 01DR.
3. Derived by multiplying APS's as-filed proforma base fuel cost of $0.029882/kWh (APS Attach. PME-04DR, p.2) and other variable costs of $0.001105/kWh (APS PME-WP26DR) times proforma class kWh energy (APS CAM-WP01DR).

AECC Reallocation of Fixed Generation Revenue Recovery

Line No.	(a) Rate Class/Schedule	(b) AECC KCH-2-RD Proforma Base Non-Fuel Revenue ($000)[1]	(c) AECC Generation Non-Fuel Revenue Reallocation (%)	(d) AECC Generation Non-Fuel Revenue Reallocation ($000)[2]	(e) = (b) + (d) AECC Adjusted Proforma Base Non-Fuel Revenue ($000)
1	Residential	1,384,270			1,384,270
2	General Service				
3	E-20	3,729			3,729
4	E-30	1,123			1,123
5	E-32 XS	177,245	35.64%	4,102	181,347
6	E-32 XS Solar Legacy	717	0.16%	19	735
7	E-32TOU XS	657	0.13%	15	672
8	E-32 S	237,523	63.11%	7,263	244,786
9	E-32TOU S	2,631	0.96%	110	2,741
10	E-32 M	236,019			236,019
11	E-32TOU M	5,189			5,189
12	GS-S M	4,810			4,810
13	GS-S L	4,971			4,971
14	E-32 L	172,181			172,181
15	E-32TOU L	14,711			14,711
16	E-30, E-32 Subtotal	857,777	100.00%	11,509	869,285
17	E-34	34,718			34,718
18	E-35	59,255			59,255
19	XHLF	11,771			11,771
20	E-35 Total	71,025			71,025
21	E-36 M	684			684
22	E-32M AG-1 (excl. Generation)	1,486			1,486
23	E-32L AG-1 (excl. Generation)	13,041			13,041
24	E-32LTOU AG-1 (excl. Generation)	303			303
25	E-34 AG-1 (excl. Generation)	3,224			3,224
26	E-35 AG-1 (excl. Generation)	6,303			6,303
27	AG-1 Generation (aggregated)	27,141		(21,509)	5,632
28	AG-1 Total	51,498		(21,509)	29,989
29	Total General Service	1,019,432	100.00%	(10,000)	1,009,432
30	Irrigation	23,274			23,274
31	Outdoor/Street Lighting	18,505			18,505
32	Dusk to Dawn Lighting	8,732			8,732
33	Total	2,454,214	100.00%	(10,000)	2,444,214

1. Data Source: AECC Exhibit KCH-2-RD.
2. Data Source: See pp. 2 - 5 for Reallocation and Fixed Generation Revenue derivation.

AECC Reallocation of Fixed Generation Revenue Recovery

	(a)	(b)	(c)	(d)	(e) = (e) Total x [(d) ÷ (d) Total]
Line No.	**Rate Schedule**	**APS Proposed Total kW[1]**	**APS Proposed Total kWh[1]**	**APS Proposed Total Generation Non-Fuel Revenue ($000)[1, 2]**	**AECC Fixed Generation Revenue Reallocation ($000)[3]**
1	E-20	200,938	38,839,498	1,103	
2	E-30	-	5,030,079	212	
3	E-32 XS	5,934,196	1,495,766,805	60,976	4,102
4	E-32 XS Solar Legacy	-	5,471,291	281	19
5	E-32 S	8,696,323	2,597,823,594	107,969	7,263
6	E-32 M	9,046,431	3,189,035,094	110,501	
7	E-32 L	7,003,986	2,860,125,088	82,311	
8	E-32TOU XS	34,248	5,950,610	225	15
9	E-32TOU S	153,110	30,973,801	1,634	110
10	E-32TOU M	354,285	72,325,864	2,306	
11	E-32TOU L	1,199,456	942,455,646	11,779	
12	E-34	1,388,591	696,342,119	19,644	
13	E-35	4,802,953	1,320,388,178	30,349	
14	E-36 M	34,452	34,452	787	
15	GS-S M	220,758	46,775,918	1,485	
16	GS-S L	246,099	59,038,435	1,783	
17	XHLF	222,607	121,131,500	2,659	
18	Total of Reallocation Classes	14,817,877	4,135,986,101	171,085	11,509

1. Data Source: APS Witness Charles A Miessner Workpaper 01DR.
2. Generation revenue calculations based off of proposed billing determinants and rates in Miessner Workpaper 01DR.
3. Fixed generation revenues allocated to AG-1 customers in APS's proposal. Data Source: Total from Exhibit KCH-3-RD, p. 4, line 21.

AECC Derivation of Fixed Generation Revenue for Reallocation
E-32 Rate Schedules

	(a)	(b)	(c)	(d) = (b) x (c)	(e)	(f) = (b) x -(e)	(g) = (f) + (d)
Line No.	As Filed Rate Schedule	APS Proposed Billing Determinants[1]	APS Proposed Unbundled Generation Rates[1]	APS Proposed Unbundled Generation Revenue	APS Fuel + Variable Generation Rates[2]	Remove APS Fuel + Variable Energy Revenue	APS Proposed Generation Non-Fuel Rev. Collected from AG-1
1	**E-32 M AG-1**			**$ 2,597,551**		**$ (1,347,564)**	**$ 1,249,987**
2	kW tier 1 - secondary	33,333	$ -	$ -	$ -	$ -	$ -
3	kW tier 2 - secondary	60,661	$ -	$ -	$ -	$ -	$ -
4	kWh - Summer Tier 1	8,322,055	$ 0.09254	$ 770,123	$ 0.03099	$ (257,876)	$ 512,247
5	kWh - Summer Tier 2	12,276,840	$ 0.05129	$ 629,679	$ 0.03099	$ (380,422)	$ 249,257
6	kWh - Winter Tier 1	9,346,874	$ 0.07616	$ 711,858	$ 0.03099	$ (289,632)	$ 422,226
7	kWh - Winter Tier 2	14,192,944	$ 0.03490	$ 495,334	$ 0.03099	$ (439,797)	$ 55,537
8	Weather Adjustment	(421,461)		$ (24,410)	$ 0.03099	$ 13,060	$ (11,350)
9	Customer Adjustment	(229,218)		$ (13,545)	$ 0.03099	$ 7,103	$ (6,442)
10	Reconciliation to Actual Proposed Revenue			$ 28,512			$ 28,512
11	**E-32 L AG-1**			**$ 23,389,651**		**$ (12,578,981)**	**$ 10,810,669**
12	kW Secondary tier 1	136,800	$ 4.136	$ 565,805	$ -	$ -	$ 565,805
13	kW Secondary tier 2	697,450	$ 4.136	$ 2,884,653	$ -	$ -	$ 2,884,653
14	kW Primary tier 1	2,400	$ 4.136	$ 9,926	$ -	$ -	$ 9,926
15	kW Primary tier 2	33,819	$ 4.136	$ 139,875	$ -	$ -	$ 139,875
16	kWh - Summer	183,243,725	$ 0.05834	$ 10,690,439	$ 0.03099	$ (5,678,173)	$ 5,012,266
17	kWh - Winter	225,344,729	$ 0.03916	$ 8,824,500	$ 0.03099	$ (6,982,757)	$ 1,841,742
18	Weather Adjustment	(3,298,651)		$ (155,754)	$ 0.03099	$ 102,215	$ (53,539)
19	Customer Adjustment	654,026		$ 37,833	$ 0.03099	$ (20,266)	$ 17,567
20	Reconciliation to Actual Proposed Revenue			$ 392,374			$ 392,374
21	**E-32 TOU L AG-1**			**$ 599,184**		**$ (365,673)**	**$ 233,511**
22	kW tier 1 - primary - On-Peak	1,192	$ 6.166	$ 7,350	$ -	$ -	$ 7,350
23	kW tier 2 - primary - On-Peak	16,064	$ 6.166	$ 99,051	$ -	$ -	$ 99,051
24	kW tier 1 - primary - Off-Peak	1,170	$ 2.346	$ 2,745	$ -	$ -	$ 2,745
25	kW tier 2 - primary - Off-Peak	17,509	$ 2.346	$ 41,076	$ -	$ -	$ 41,076
26	kWh - Summer - On-Peak	922,048	$ 0.05706	$ 52,612	$ 0.03099	$ (28,572)	$ 24,041
27	kWh - Summer - Off-Peak	5,084,156	$ 0.04378	$ 222,584	$ 0.03099	$ (157,543)	$ 65,042
28	kWh - Winter - On-Peak	943,418	$ 0.04194	$ 39,567	$ 0.03099	$ (29,234)	$ 10,333
29	kWh - Winter - Off-Peak	5,114,598	$ 0.02866	$ 146,584	$ 0.03099	$ (158,486)	$ (11,902)
30	Weather Adjustment	(56,219)		$ (2,100)	$ 0.03099	$ 1,742	$ (358)
31	Customer Adjustment	(207,155)		$ (10,245)	$ 0.03099	$ 6,419	$ (3,826)
32	Reconciliation to Actual Proposed Revenue			$ (40)			$ (40)

1. Data Source: APS Witness Charles A Miessner Workpaper 01DR.
2. Base fuel rate and variable energy costs calculated as follows:
   - Base Fuel Rate = $0.029882/kWh. Source: APS Witness Peter M. Ewen Workpaper 15DR
   - Variable Energy Cost = chemical costs + water costs + SO2 margins = $0.001105/kWh. Source: APS Witness Peter M. Ewen Workpaper 26DR

AECC Derivation of Fixed Generation Revenue for Reallocation
Rate Schedules E-34 and E-35

Line No.	(a) As Filed Rate Schedule	(b) APS Proposed Billing Determinants[1]	(c) APS Proposed Unbundled Generation Rates[1]	(d) = (b) x (c) APS Proposed Unbundled Generation Revenue	(e) APS Fuel + Variable Generation Rates[2]	(f) = (b) x -(e) Remove APS Fuel + Variable Energy Revenue	(g) = (f) + (d) APS Proposed Generation Non-Fuel Rev. Collected from AG-1
1	**E-34 AG-1**			**$ 7,560,337**		**$ (3,842,944)**	**$ 3,717,393**
2	kW - Secondary Service	181,453	$ 10.770	$ 1,954,249	$ -	$ -	$ 1,954,249
3	kW - Primary Service	58,088	$ 10.770	$ 625,608	$ -	$ -	$ 625,608
4	kWh	121,390,720	$ 0.03802	$ 4,615,275	$ 0.03099	$ (3,761,534)	$ 853,741
5	Weather Adjustment	-		$ -			$ -
6	Customer Adjustment	2,627,230		$ 122,326	$ 0.03099	$ (81,410)	$ 40,916
7	Reconciliation to Actual Proposed Revenue			$ 242,879			$ 242,879
8	**E-35 AG-1**			**$ 25,543,728**		**$ (14,413,318)**	**$ 11,130,410**
9	kW - Secondary Service - On-Peak	196,144	$ 7.717	$ 1,513,643	$ -	$ -	$ 1,513,643
10	kW - Secondary Service - Off-Peak	251,760	$ 2.188	$ 550,851	$ -	$ -	$ 550,851
11	kW - Transmission Service - On-Peak	616,360	$ 7.717	$ 4,756,450	$ -	$ -	$ 4,756,450
12	kW - Transmission Service - Off-Peak	565,832	$ 2.188	$ 1,238,040	$ -	$ -	$ 1,238,040
13	kWh - On-Peak	149,819,689	$ 0.04330	$ 6,487,193	$ 0.03099	$ (4,642,463)	$ 1,844,730
14	kWh - Off-Peak	305,430,349	$ 0.03370	$ 10,293,003	$ 0.03099	$ (9,464,370)	$ 828,633
15	Weather Adjustment	-		$ -			$ -
16	Customer Adjustment	9,890,749		$ 539,738	$ 0.03099	$ (306,485)	$ 233,253
17	Reconciliation to Actual Proposed Revenue			$ 164,810			$ 164,810
18	**AG-1 Total before PSA Mitigation Adjustment**			**$ 59,690,450**		$ (32,548,480)	**$ 27,141,970**
19	Less: AECC Recommended Capacity Reserve Revenue (see p. 5)						(5,633,323)
20	Less: PSA AG-1 Mitigation Adjustment						$ (10,000,000)
21	**Final AG-1 Revenue Adjustment**						**$ 11,508,647**

1. Data Source: APS Witness Charles A Miessner Workpaper 01DR.
2. Base fuel rate and variable energy costs calculated as follows:
   - Base Fuel Rate = $0.029882/kWh. Source: APS Witness Peter M. Ewen Workpaper 15DR
   - Variable Energy Cost = chemical costs + water costs + SO2 margins = $0.001105/kWh. Source: APS Witness Peter M. Ewen Workpaper 26DR

AG-1 Capacity Reserve Charge Calculation

	(a)	(b)	(c)		(d)		(e)
Line No.	AG-1 Rate Schedule	Total Demand (kW)	Percent 30% Demand (kW)		Reserve Service Charge ($/kW)		Total Charge
1	**E-32 M**	**93,994**	**28,198**	$	9.233	$	260,354
2	Summer - kW Secondary tier 1	16,303					
3	Summer - kW Secondary tier 2	28,039					
4	Winter - kW Secondary tier 1	17,030					
5	Winter - kW Secondary tier 2	32,622					
6	**E-32 L**	**870,469**	**261,141**	$	9.233	$	2,411,112
7	Summer - kW Secondary tier 1	68,400					
8	Summer - kW Secondary tier 2	328,311					
9	Summer - kW Primary tier 1	1,200					
10	Summer - kW Primary tier 2	15,536					
11	Winter - kW Secondary tier 1	68,400					
12	Winter - kW Secondary tier 2	369,139					
13	Winter - kW Primary tier 1	1,200					
14	Winter - kW Primary tier 2	18,283					
15	**E-32 L TOU**	**17,256**	**5,177**	$	9.233	$	47,797
16	Summer - kW tier 1 - primary - on	594					
17	Summer - kW tier 2 - primary - on	8,011					
18	Winter - kW tier 1 - primary - on	598					
19	Winter - kW tier 2 - primary - on	8,053					
20	**E-34**	**239,541**	**71,862**	$	9.233	$	663,505
21	Secondary Service	181,453					
22	Primary Service	58,088					
23	**E-35**	**812,504**	**243,751**	$	9.233	$	2,250,555
24	Secondary - On-Peak kW	196,144					
25	Transmission - On-Peak kW	616,360					
26	Total	2,033,764	610,129			$	5,633,323

AECC Proposed Changes to APS Rate Spread
Combined Impact of Base Rates and Rider Resets
at APS's Proposed $166 Million Net Revenue Increase

(Assumes Continuation of AG-1 per AECC Proposal)

Line No.	Rate Class/Schedule (a)	Current Proforma Base Revenue ($000)[1] (b)	Transfer of Rider Revenue ($000)[2] (c)	AECC Net Revenue Increase ($000) (d) = (g) - (b) - (c)	APS Proposed Proforma Base Fuel + Other Var. Revenue ($000)[3] (e)	AECC Proposed Proforma Base Non-Fuel Revenue ($000)[4] (f)	AECC Proposed Proforma Base Revenue ($000) (g) = (e) + (f)	Proposed Adjusted Proforma Base Revenue Increase (%) (h) = (d) ÷ (b)	AECC Class Share of Revenue Requirement (%) (i) = (g) ÷ [(g) Total - AG-1 (gen.)]
1	Residential	1,486,578	168,607	144,824	415,738	1,384,270	1,800,009	9.74%	55.0%
2	General Service								
3	E-20	4,069	461	367	1,167	3,729	4,896	9.01%	0.1%
4	E-30	1,206	55	20	157	1,123	1,281	1.70%	0.0%
5	E-32 XS	210,347	18,198	(1,044)	46,154	181,347	227,501	-0.50%	6.9%
6	E-32 XS Solar Legacy	802	69	(0)	135	735	871	-0.05%	0.0%
7	E-32TOU XS	792	65	(1)	184	672	856	-0.12%	0.0%
8	E-32 S	299,099	25,549	275	80,137	244,786	324,923	0.09%	9.9%
9	E-32TOU S	3,376	269	51	955	2,741	3,696	1.50%	0.1%
10	E-32 M	305,191	23,581	4,491	97,245	236,019	333,263	1.47%	10.2%
11	E-32TOU M	6,774	483	141	2,210	5,189	7,398	2.09%	0.2%
12	GS-S M	5,421	488	348	1,446	4,810	6,257	6.41%	0.2%
13	GS-S L	5,924	572	338	1,862	4,971	6,834	5.70%	0.2%
14	E-32 L	239,240	12,578	8,328	87,965	172,181	260,146	3.48%	7.9%
15	E-32TOU L	20,381	1,079	706	7,455	14,711	22,166	3.46%	0.7%
16	E-30, E-32 Subtotal	1,098,553	82,986	13,653	325,906	869,285	1,195,191	1.24%	36.5%
17	E-34	50,469	2,842	3,409	22,002	34,718	56,720	6.75%	1.7%
18	E-35	114,279	5,482	5,983	54,719	71,025	125,744	5.24%	3.8%
19	E-36 M	829	61	62	267	684	952	7.42%	0.0%
20	E-32M AG-1 (excl. Generation)	1,060	124	302		1,486	1,486	28.49%	0.0%
21	E-32L AG-1 (excl. Generation)	10,859	1,211	971		13,041	13,041	8.94%	0.4%
22	E-32LTOU AG-1 (excl. Generation)	202	18	83		303	303	41.09%	0.0%
23	E-34 AG-1 (excl. Generation)	2,916	344	(36)		3,224	3,224	-1.23%	0.1%
24	E-35 AG-1 (excl. Generation)	5,223	880	200		6,303	6,303	3.83%	0.2%
25	AG-1 Generation (aggregated)	55,468		(17,287)	32,548	5,632	38,181	-31.17%	
26	AG-1 Total	75,728	2,577	(15,767)	32,548	29,989	62,538	-20.82%	0.7%
27	Total General Service	1,343,926	94,409	7,705	436,608	1,009,432	1,446,040	0.57%	43.0%
28	Irrigation	28,739	3,243	1,649	10,357	23,274	33,631	5.74%	1.0%
29	Outdoor/Street Lighting	21,082	979	1,151	4,707	18,505	23,212	5.46%	0.7%
30	Dusk to Dawn Lighting	8,578	313	554	713	8,732	9,445	6.46%	0.3%
31	Sub-Total	2,888,903	267,551	155,883	868,123	2,444,214	3,312,337	5.40%	100.0%
32	APS PSA AG-1 Mitigation Revenue			10,000					
33	Total	2,888,903	267,551	165,883	868,123	2,444,214	3,312,337	5.74%	

1. Data Source: APS Miessner Schedule H-2 workpaper CAM-WP01DR with APS's E-34/E-35 correction provided in APS's Response to Staff Data Request 10.3.
2. Data Source: APS Witness Charles A Miessner Workpaper 01DR.
3. Derived by multiplying APS's as-filed proforma base fuel cost of $0.029882/kWh (APS Attach. PME-04DR, p.2) and other variable costs of $0.001105/kWh (APS PME-WP26DR) times proforma class kWh energy (APS CAM-WP01DR).
4. At APS's Proposed Revenue Requirement. Data Source: AECC Exhibit KCH=3-RD, Column (e).

AECC "Tentative" Rate Spread
Combined Impact of Base Rates and Rider Resets
at AECC's Proposed Revenue Requirement
($81.3 Million Revenue Reduction to APS's Revenue Proposal)

(Assumes Continuation of AG-1 per AECC Proposal and Permits Net Reductions)

	(a)	(b)	(c)	(d) = (g) - (b) - (c)	(e)	(f) = (g) - (e)	(g) = (g) Total x (i)	(h) = (d) ÷ (b)	(i) See KCH-4-RD
Line No.	Rate Class/Schedule	Current Proforma Base Revenue ($000)[1,2]	Transfer of Rider Revenue ($000)[2]	AECC Net Revenue Increase ($000)	APS Proposed Proforma Base Fuel + Other Var. Revenue ($000)[3]	AECC Proposed Proforma Base Non-Fuel Revenue ($000)	AECC Proposed Proforma Base Revenue ($000)	AECC Proposed Adjusted Proforma Base Revenue Increase (%)	AECC Class Share of Revenue Requirement (%)[4]
1	Residential	1,486,578	168,607	100,110	415,738	1,339,557	1,755,295	6.73%	55.0%
2	General Service								
3	E-20	4,069	461	245	1,167	3,608	4,774	6.02%	0.1%
4	E-30	1,206	55	(11)	157	1,092	1,249	-0.94%	0.0%
5	E-32 XS	210,347	18,198	(6,696)	46,154	175,696	221,849	-3.18%	6.9%
6	E-32 XS Solar Legacy	802	69	(22)	135	714	849	-2.75%	0.0%
7	E-32TOU XS	792	65	(22)	184	651	835	-2.80%	0.0%
8	E-32 S	299,099	25,549	(7,796)	80,137	236,714	316,852	-2.61%	9.9%
9	E-32TOU S	3,376	269	(41)	955	2,649	3,604	-1.22%	0.1%
10	E-32 M	305,191	23,581	(3,787)	97,245	227,740	324,985	-1.24%	10.2%
11	E-32TOU M	6,774	483	(42)	2,210	5,005	7,215	-0.63%	0.2%
12	GS-S M	5,421	488	192	1,446	4,655	6,101	3.54%	0.2%
13	GS-S L	5,924	572	168	1,862	4,801	6,664	2.83%	0.2%
14	E-32 L	239,240	12,578	1,866	87,965	165,719	253,684	0.78%	7.9%
15	E-32TOU L	20,381	1,079	155	7,455	14,160	21,615	0.76%	0.7%
16	E-30, E-32 Subtotal	1,098,553	82,986	(16,037)	325,906	839,596	1,165,502	-1.46%	36.5%
17	E-34	50,469	2,842	2,000	22,002	33,309	55,311	3.96%	1.7%
18	E-35	114,279	5,482	2,859	54,719	67,902	122,620	2.50%	3.8%
19	E-36 M	829	61	38	267	661	928	4.57%	0.0%
20	E-32M AG-1 (excl. Generation)	1,060	124	265		1,449	1,449	25.01%	0.0%
21	E-32L AG-1 (excl. Generation)	10,859	1,211	647		12,717	12,717	5.96%	0.4%
22	E-32LTOU AG-1 (excl. Generation)	202	18	75		295	295	37.36%	0.0%
23	E-34 AG-1 (excl. Generation)	2,916	344	(116)		3,144	3,144	-3.98%	0.1%
24	E-35 AG-1 (excl. Generation)	5,223	880	43		6,146	6,146	0.83%	0.2%
25	AG-1 Generation (aggregated)	55,468		(17,287)	32,548	5,632	38,181	-31.17%	0.0%
26	AG-1 Total	75,728	2,577	(16,372)	32,548	29,384	61,933	-21.62%	0.7%
27	Total General Service	1,343,926	94,409	(27,267)	436,608	974,460	1,411,068	-2.03%	43.0%
28	Irrigation	28,739	3,243	814	10,357	22,439	32,796	2.83%	1.0%
29	Outdoor/Street Lighting	21,082	979	574	4,707	17,928	22,635	2.72%	0.7%
30	Dusk to Dawn Lighting	8,578	313	319	713	8,498	9,210	3.72%	0.3%
31	Sub-Total	2,888,903	267,551	74,550	868,123	2,362,881	3,231,004	2.58%	100.0%
32	APS PSA AG-1 Mitigation Revenue			10,000					
33	Total	2,888,903	267,551	84,550	868,123	2,362,881	3,231,004	2.93%	

1. Data Source: APS Standard Filing Requirement Schedule H-2.
2. Data Source: APS Witness Charles A Miessner Workpaper 01DR.
3. Derived by multiplying APS's as-filed proforma base fuel cost of $0.029882/kWh (APS Attach. PME-04DR, p 2) and other variable costs of $0.001105/kWh (APS PME-WP26DR) times proforma class kWh energy (APS CAM-WP01DR).
4. Data Source: AECC Exhibit KCH-4-RD, Column (i).

AECC Proposed Rate Spread
Combined Impact of Base Rates and Rider Reset
at AECC's Proposed Revenue Requirement
($81.3 Million Revenue Reduction to APS's Revenue Proposal)

(Assumes Continuation of AG-1 per AECC Proposal and No Net Rate Reductions)

Line No.	(a) Rate Class/Schedule	(b) Current Proforma Base Revenue ($000)[1,2]	(c) Transfer of Rider Revenue ($000)[2]	(d) = (g) - (b) - (c) AECC Class AECC Net Revenue Increase ($000)	(e) APS Proposed Proforma Base Fuel + Other Var. Revenue ($000)[3]	(f) = (g) - (e) AECC Proposed Proforma Base Non-Fuel Revenue ($000)	(g) = (g) Total x (i) AECC Proposed Proforma Base Revenue ($000)	(h) = (d) ÷ (b) AECC Proposed Adjusted Proforma Base Revenue Increase (%)	(i) = (g) ÷ [(g) Total - AG-1 (gen.)] AECC Class Share of Revenue Requirement (%)
1	Residential	1,486,578	168,607	85,836	415,738	1,325,282	1,741,021	5.77%	54.5%
2	General Service								
3	E-20	4,069	461	206	1,167	3,569	4,736	5.06%	0.1%
4	E-30	1,206	55	0	157	1,103	1,261	0.00%	0.0%
5	E-32 XS	210,347	18,198	0	46,154	182,391	228,545	0.00%	7.2%
6	E-32 XS Solar Legacy	802	69	0	135	736	871	0.00%	0.0%
7	E-32TOU XS	792	65	0	184	673	857	0.00%	0.0%
8	E-32 S	299,099	25,549	0	80,137	244,511	324,648	0.00%	10.2%
9	E-32TOU S	3,376	269	0	955	2,690	3,645	0.00%	0.1%
10	E-32 M	305,191	23,581	0	97,245	231,527	328,772	0.00%	10.3%
11	E-32TOU M	6,774	483	0	2,210	5,047	7,257	0.00%	0.2%
12	GS-S M	5,421	488	142	1,446	4,605	6,051	2.63%	0.2%
13	GS-S L	5,924	572	114	1,862	4,747	6,610	1.92%	0.2%
14	E-32 L	239,240	12,578	0	87,965	163,853	251,818	0.00%	7.9%
15	E-32TOU L	20,381	1,079	0	7,455	14,005	21,460	0.00%	0.7%
16	E-30, E-32 Subtotal	1,098,553	82,986	256	325,906	855,889	1,181,795	0.02%	37.0%
17	E-34	50,469	2,842	1,550	22,002	32,860	54,861	3.07%	1.7%
18	E-35	114,279	5,482	1,862	54,719	67,902	121,623	1.63%	3.8%
19	E-36 M	829	61	30	267	653	920	3.66%	0.0%
20	E-32M AG-1 (excl. Generation)	1,060	124	265		1,449	1,449	25.01%	0.0%
21	E-32L AG-1 (excl. Generation)	10,859	1,211	647		12,717	12,717	5.96%	0.4%
22	E-32LTOU AG-1 (excl. Generation)	202	18	75		295	295	37.36%	0.0%
23	E-34 AG-1 (excl. Generation)	2,916	344	(116)		3,144	3,144	-3.98%	0.1%
24	E-35 AG-1 (excl. Generation)	5,223	880	43		6,146	6,146	0.83%	0.2%
25	AG-1 Generation (aggregated)	55,468		(17,287)	32,548	5,632	38,181	-31.17%	
26	AG-1 Total	75,728	2,577	(16,372)	32,548	29,384	61,933	-21.62%	0.7%
27	Total General Service	1,343,926	94,409	(12,467)	436,608	990,256	1,425,868	-0.93%	43.5%
28	Irrigation	28,739	3,243	547	10,357	22,172	32,529	1.90%	1.0%
29	Outdoor/Street Lighting	21,082	979	390	4,707	17,744	22,451	1.85%	0.7%
30	Dusk to Dawn Lighting	8,578	313	244	713	8,423	9,135	2.85%	0.3%
31	Sub-Total	2,888,903	267,551	74,550	868,123	2,363,878	3,231,004	2.58%	100.0%
32	APS PSA AG-1 Mitigation Revenue			10,000					
33	Total	2,888,903	267,551	84,550	868,123	2,363,878	3,231,004	2.93%	

1. Data Source: APS Standard Filing Requirement Schedule H-2.
2. Data Source: APS Witness Charles A Miessner Workpaper 01DR.
3. Derived by multiplying APS's as-filed proforma base fuel cost of $0.029882/kWh (APS Attach. PME-04DR, p.2) and other variable costs of $0.001105/kWh (APS PME-WP26DR) times proforma class kWh energy (APS CAM-WP01DR).

Exhibit KCH-7-RD

APS's Response to
AECC Data Request 19.1

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
NINETEENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
JANUARY 17, 2016

AECC 19.1: Please refer to Attachment LRS-06DR, p. 4.

a. Since the inception of the AG-1 program, has a GSP ever failed to deliver power to an AG-1 customer (i.e., provided zero MW)? If yes, please provide a log of instances in which a GSP has failed to deliver power including the duration and amount of power that the GSP failed to deliver.

b. Does APS contend that GSP failure to deliver power has been an operational problem during the history of the AG-1 program?

Response:

a. No. Actual power deliveries have equaled the scheduled amounts.

b. No. The operational problem has been that the scheduled amounts have not matched the customer's load, which is one of the program requirements.

Witness: Chuck Miessner